MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

The following Management's Discussion and Analysis ("MD&A") is a review of the operational and financial results and outlook for Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") for the three and nine months ended September 30, 2017 and 2016. This MD&A is dated and based on information available on November 7, 2017 and should be read in conjunction with the unaudited condensed consolidated interim financial statements and notes for the three and nine months ended September 30, 2017 and 2016. Additional information relating to Tamarack, including Tamarack's Annual Information Form, is available on SEDAR at www.sedar.com and Tamarack's website at www.tamarackvalley.ca.

The condensed consolidated interim financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). The Company uses certain non-IFRS and additional IFRS measures in this MD&A. For a discussion of those measures, including the method of calculation, please refer to the section titled "Non-IFRS and Additional IFRS Measures" beginning on page 15. Unless otherwise indicated, all references to dollar amounts are in Canadian currency.

About Tamarack

Tamarack is an oil and gas exploration and production company committed to long-term growth and the identification, evaluation and operation of resource plays in the Western Canadian Sedimentary Basin. Tamarack's strategic direction is focused on two key principles – targeting repeatable and relatively predictable plays that provide long-life reserves, and using a rigorous, proven modeling process to carefully manage risk and identify opportunities. The Company has an extensive inventory of low-risk, oil development drilling locations focused primarily in the Cardium and Viking fairways in Alberta and Saskatchewan that are economic over a range of oil and natural gas prices. With this type of portfolio and an experienced and committed management team, Tamarack intends to continue delivering on its strategy to maximize shareholder returns while managing its balance sheet.

Transformative Business Combination Expands Viking Oil Assets

On January 11, 2017, Tamarack closed the previously announced arrangement agreement (the "Arrangement Agreement") providing for the acquisition by Tamarack of all of the issued and outstanding common shares of Spur Resources Ltd. ("Spur"), which held Spur's Viking oil assets at closing (the "Viking Acquisition"). Under the terms of the Arrangement Agreement, the Company issued an aggregate of 90.1 million common shares of Tamarack and paid $58.0 million in cash. Tamarack also assumed Spur's net debt, estimated to be $23.7 million as at January 11, 2017, after accounting for proceeds from the exercise of all outstanding options of Spur, including severance and transaction costs. Based upon Tamarack's share price on January 11, 2017 of $3.44 per share, the total consideration paid by Tamarack, including the assumption of debt, was approximately $391 million.

Production

	Three months ended September 30,			Nine months ended September 30,		
	2017	2016	% change	**2017**	2016	% change
Production						
Light oil (bbls/d)	**10,108**	4,534	123	**9,168**	3,999	129
Heavy oil (bbls/d)	**603**	343	76	**514**	379	36
Natural gas liquids (bbls/d)	**1,499**	1,078	39	**1,576**	1,021	54
Natural gas (mcf/d)	**49,987**	29,007	72	**47,860**	27,435	74
Total (boe/d)	**20,541**	10,790	90	**19,235**	9,972	93
Percentage of oil and natural gas liquids	**59%**	55%		**59%**	54%	

Average production for the third quarter of 2017 increased by 6% to 20,541 boe/d from 19,336 boe/d in the second quarter of 2017. Third quarter 2017 volumes were positively impacted by the third quarter drilling program which contributed an additional 674 boe/d from Wilson Creek/Alder Flats as a result of a Mannville gas well which came on-stream during quarter (31% oil and natural gas liquids) and 1,514 boe/d from the Viking development program (87% oil and natural gas liquids). These gains were partially offset by expected declines from legacy Tamarack volumes and 408 boe/d related to the shut-in of the TransGas Coleville Gas Plant ("Coleville Plant"). The Coleville Plant commenced partial operations in the middle of July, with full-scale operations expected to resume later in the year. Tamarack continues to have Coleville production curtailed by approximately 1.0 mmcf/d and 15 bbls/d of NGLs.

The Company's oil weighting increased by 2% in the third quarter of 2017, to 52% compared to 51% in the second quarter of 2017 due to the higher oil-weighted drilling program in the Veteran area of Alberta. For the remainder of 2017, the Company expects its oil weighting to remain in the 53 to 55% range with the combined oil and natural gas liquids weighting expected to fluctuate between 59% and 62%. This weighting is dependent on the timing of production additions from the higher oil-weighted areas of Wilson Creek, Penny and the Viking Acquisition assets, and additions from the higher natural gas-weighted area of Alder Flats. Oil and natural gas weightings may also be affected by production additions associated with future drilling of liquids-rich Mannville gas wells in the Wilson Creek area and capacity changes at the Coleville Plant.

Crude oil and natural gas liquids production in the third quarter of 2017 continued to increase and averaged 12,210 bbls/d, an increase of 7% compared to 11,387 bbls/d in the second quarter of 2017. The increase in oil and liquids production was due to the third quarter drilling program which contributed an additional 208 bbls/d from Wilson Creek/Alder Flats and 1,291 bbls/d from the Viking development program. These gains were partially offset by expected declines from legacy Tamarack volumes and 17 bbls/d related to the shut-in of the Coleville Plant. Tamarack's oil and natural gas liquids volumes represented 59% of total production in both the second and third quarters of 2017 compared to 55% in the third quarter of 2016.

Natural gas production averaged 49,987 mcf/d in the third quarter of 2017, an increase of 5% over the 47,696 mcf/d produced in the prior quarter. The production increase was due to the third quarter drilling program which contributed an additional 2,795 mcf/d from Wilson Creek/Alder Flats and 1,336 mcf/d from the Viking development program, partially offset by expected declines from legacy Tamarack volumes and 2,347 mcf/d related to the shut-in of the Coleville Plant.

Compared to the prior year, average third quarter 2017 production increased by 90% to 20,541 boe/d from 10,790 boe/d during the same period in 2016 with average production for the nine months ended

September 30, 2017 increasing by 93% to 19,235 boe/d from 9,972 boe/d during the same period in 2016. These increases are attributable to the successful drilling programs in 2016 and 2017, as well as the impact of production from assets acquired in the Viking Acquisition and Penny and Redwater Acquisitions, partially offset by expected declines from existing production.

Petroleum, Natural Gas Sales and Royalties

	Three months ended September 30,			Nine months ended September 30,		
	2017	2016	% change	**2017**	2016	% change
Revenue ($ thousands)						
Oil and NGLs	**$56,493**	$24,810	128	**$161,084**	$60,114	168
Natural gas	**7,434**	6,778	10	**32,428**	15,610	108
Total	**$63,927**	$31,588	102	**$193,512**	$75,724	156
Average realized price						
Light oil ($/bbl)	**53.43**	51.83	3	**56.89**	47.19	21
Heavy oil ($/bbl)	**46.26**	39.29	18	**45.03**	32.89	37
Natural gas liquids ($/bbl)	**30.76**	19.68	56	**28.74**	17.83	61
Combined average oil and NGLs ($/boe)	**50.29**	45.29	11	**52.41**	40.64	29
Natural gas ($/mcf)	**1.62**	2.54	(36)	**2.48**	2.08	19
Revenue ($/boe)	**33.83**	31.82	6	**36.85**	27.72	33
Benchmark pricing:						
Edmonton Par (Cdn$/bbl)	**57.03**	54.33	5	**60.66**	48.74	24
Hardisty Heavy (Cdn$/bbl)	**47.20**	40.14	18	**49.67**	35.68	39
AECO daily index (Cdn$/mcf)	**1.45**	2.31	(37)	**2.30**	1.84	25
AECO monthly index (Cdn$/mcf)	**2.03**	2.19	(7)	**2.57**	1.84	40
Royalty expenses ($ thousands)	**$7,043**	$2,220	217	**$20,670**	$5,049	309
$/boe	**3.73**	2.24	67	**3.94**	1.85	113
percent of sales	**11**	7	57	**11**	7	57

Revenue from crude oil, natural gas and associated natural gas liquids sales was $63.9 million in the third quarter of 2017, which was 4% lower than the $66.7 million generated in the second quarter of 2017. This decrease is attributable to a 46% reduction in pricing for natural gas and a 3% reduction in pricing for crude oil and natural gas liquids, partially offset by a 7% increase in crude oil and natural gas liquids production and a 5% increase in natural gas production.

Compared to the same period in 2016, revenue in the third quarter of 2017 increased 102% from $31.6 million primarily due to a 105% increase in crude oil and natural gas liquids production, a 72% increase in natural gas production, as well as 11% higher product prices for crude oil and natural gas liquids, partially offset by a 36% decrease in natural gas prices.

Revenue for the nine months ended September 30, 2017 increased 156% relative to the same period in 2016 primarily due to a 109% increase in crude oil and natural gas liquids production and a 74% increase in natural gas production, as well as 29% higher product prices for crude oil and natural gas liquids and 19% higher prices for natural gas.

WTI crude markets remained depressed for most of the third quarter of 2017, after having dropped to a one-year low of US$42.53/bbl in June. The average third quarter WTI price of US$48.46/bbl was similar to the average second quarter price of US$48.29/bbl. While the narrow WTI to Edmonton differential added value to the Canadian price per barrel, the strength of the Canadian dollar lowered the realized price for the Edmonton Par Benchmark relative to the previous quarters. During the third quarter, Edmonton Par was 5% higher than the same period in 2016, but decreased 6% quarter over quarter due to higher average WTI oil prices in the second quarter of 2017. Tamarack's realized light oil price for the three months ended September 30, 2017 was $53.43/bbl versus $55.58/bbl in the previous quarter and $51.83/bbl in the third quarter of 2016, a 4% decrease and 3% increase, respectively.

Conversely, natural gas liquids prices increased to $30.76/bbl from $29.39/bbl in the second quarter of 2017 and $19.68/bbl in the third quarter of 2016, a 5% increase and a 56% increase, respectively. Natural gas liquids contracts are generally negotiated annually, with new contracts beginning April 1 each year. Realized natural gas liquids prices improved despite a decreasing Edmonton Par benchmark due to improved natural gas liquids contracts for the 2017 renewal period. Contract improvements for 2017 result from stronger market conditions, including significantly improved propane prices and increased butane prices relative to the period when the 2016 contracts were negotiated, as well as the surplus of available liquids fractionation capacity in the province, which has resulted in more competitive product pricing and lower deductions. Quarter over quarter improvements are due largely to the steady increase in propane prices across 2017. While most of the Company's liquids are priced relative to WTI, propane sales are priced at market, which resulted in an increased price per bbl on natural gas liquids.

The AECO daily index decreased 48% quarter over quarter and 37% over the third quarter of 2016. Third quarter 2017 realized prices averaged $1.62/mcf for natural gas compared to $3.01/mcf in the previous quarter and $2.54/mcf in the third quarter of 2016, a 46% and 36% decrease, respectively. A large majority of Tamarack's gas is priced relative to the AECO Daily index and should generally correlate to this index; however, realized pricing may not correlate quarter over quarter to the AECO Monthly index due to large daily fluctuations. Tamarack will continue to monitor market conditions for all products in order to make effective capital allocation decisions.

As discussed in Tamarack's second quarter report, cuts to natural gas deliveries out of Alberta, as well as cuts to storage injections, resulted in significant price reductions during the third quarter. Gas prices are expected to improve through the remainder of 2017, as a result of weather-related demand. Tamarack expects the summer volatility experienced in the daily index to persist through 2018 and beyond as gas takeaway capacity is limited and oversupply in Alberta continues. Subsequent to the quarter, Tamarack entered into a gas sales contract with a third party to diversify its natural gas price exposure. Commencing November 1, 2017, Tamarack will receive a mix of Malin, Chicago, Michigan Consolidated and Dawn daily index pricing less transportation tolls on approximately 20% of its natural gas production. Tamarack continues to explore ways of minimizing exposure to Alberta gas market fluctuations.

At September 30, 2017, the Company held derivative commodity and financial contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	2,000 bbls/day	October 1, 2017 – December 31, 2017	WTI fixed price	Cdn $70.83
Crude oil	600 bbls/day	October 1, 2017 – December 31, 2017	WTI fixed price	US $55.08
Crude oil	600 bbls/day	October 1, 2017 – December 31, 2017	Written call option	Cdn $81.90
Crude oil	200 bbls/day	January 1, 2018 – March 31, 2018	WTI fixed price	Cdn $73.50
Crude oil	1,700 bbls/day	January 1, 2018 – March 31, 2018	WTI fixed price	US $53.11
Crude oil	1,500 bbls/day	April 1, 2018 – June 30, 2018	WTI fixed price	US $51.90
Crude oil	900 bbls/day	July 1, 2018 – September 30, 2018	WTI fixed price	US $51.80
Crude oil	700 bbls/day	October 1, 2018 – December 31, 2018	WTI fixed price	US $51.93
Natural gas	25,000 GJ/day	October 1, 2017 – December 31, 2017	AECO fixed price	Cdn $2.91
Natural gas	25,000 GJ/day	January 1, 2018 – March 31, 2018	AECO fixed price	Cdn $3.16
Foreign exchange	995,000 US$/month	October 1, 2017 – March 31, 2018	Exchange rate	Cdn $1.35

At September 30, 2017, the commodity contracts were fair valued with an asset of $6.0 million (December 31, 2016 – $10.7 million liability) recorded on the balance sheet. The effect of the unrealized gains on the statement of comprehensive income included an increase to earnings of $17.0 million for the nine months ended September 30, 2017 (loss of $15.5 million for the same period in 2016) and loss to earnings of $2.7 million for the three months ended September 30, 2017 (loss of $0.5 million for the same period in 2016).

All physical commodity contracts are considered executory contracts and are not recorded at fair value on the balance sheet. On settlement, the realized benefit or loss is recognized in oil and natural gas revenue. At September 30, 2017, the Company held the following physical commodity contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	1,000 bbls/day	October 1, 2017 – December 31, 2017	WTI/Edm Differential	US $3.25
Crude oil	1,500 bbls/day	October 1, 2017 – December 31, 2017	WTI/Edm Differential	US $3.20
Crude oil	45,000 bbls/month	October 1, 2017 – December 31, 2017	WTI/Edm Differential	US $3.00

Since September 30, 2017, the Company has entered into the following derivative contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude Oil	1,800 bbls/day	January 1, 2018 – March 31, 2018	WTI fixed price	US $53.65
Crude Oil	1,800 bbls/day	April 1, 2018 – June 30, 2018	WTI fixed price	US $53.24
Crude Oil	1,500 bbls/day	July 1, 2018 – September 30, 2018	WTI fixed price	US $53.04
Crude Oil	700 bbls/day	October 1, 2018 – December 31, 2018	WTI fixed price	US $53.04
Foreign exchange	600,000 US$/month	January 1, 2018 – March 31, 2018	Exchange Rate	Cdn $1.2584
Foreign exchange	720,000 US$/month	April 1, 2018 – June 30, 2018	Exchange Rate	Cdn $1.2869

Royalty expenses for the third quarter of 2017 were $3.73/boe or $7.0 million, representing 11% of revenue, which were comparable to $3.97/boe or $7.0 million for the second quarter of 2017, representing 10% of revenue.

Royalties as a percentage of revenue were higher in the third quarter of 2017 compared to the third quarter of 2016, when royalty expenses were $2.24/boe or $2.2 million, representing 7% of revenue. The increase in royalties as a percentage of revenue for the third quarter of 2017 over the same period in 2016 is due to the sliding scale mechanism which results in higher royalties when commodity prices increase, coupled with the impact of the Viking Acquisition and subsequent Viking drilling program which have a slightly higher royalty rate.

The royalty expense for the first nine months of 2017 was $3.94/boe or $20.7 million, representing 11% of revenue, compared to $1.85/boe or $5.0 million, representing 7% of revenue for the same period in 2016. Relative to the same period in 2016, the increase in royalties as a percentage of revenue for the nine months ended September 30, 2017 is due to the sliding scale mechanism which results in higher royalties when commodity prices increase and the impact of the Viking Acquisition wells which have a higher rate than the corporate average.

The Company expects royalty rates as a percentage of revenue to remain in the 10 to 13% range for the remainder of 2017.

Production Expenses

	Three months ended September 30,			Nine months ended September 30,		
($ thousands, except per boe)	**2017**	2016	% change	**2017**	2016	% change
Total production expenses	**$21,271**	$11,494	85	**$60,421**	$31,241	93
Total ($/boe)	**$11.26**	$11.58	(3)	**$11.51**	$11.43	1

Production expenses for the third quarter of 2017 decreased 5% to $11.26/boe compared to $11.85/boe during the second quarter of 2017. With the partial restart of the Coleville Plant, production no longer needed to be redirected to third party facilities with higher associated fees, reducing production expenses by approximately $0.36/boe. During the latter half of the third quarter, the oil battery expansion and installation of water handling facilities in the Veteran area was completed, significantly reducing water trucking and disposal costs. This resulted in a reduction of approximately $0.25/boe to the average product costs per boe in the quarter. On an absolute basis, overall costs increased in the third quarter of 2017 to $21.3 million compared to $20.9 million in the second quarter of 2017. The increase in total production costs was driven by a 6% increase in production, partially offset by a decrease in per unit costs as described above.

On a per boe basis, third quarter 2017 production expenses were lower compared to the $11.58/boe realized in the same quarter of 2016 and on an absolute basis increased 85% to $21.3 million, compared to $11.5 million for the third quarter of 2016, matching the increase in production volumes over the same period.

Production expenses for the first nine months of 2017 increased by 1% to $11.51/boe compared to $11.43/boe for the same period in 2016 and increased 93% on an absolute basis to $60.4 million compared to $31.2 million for the same period in 2016. These increases tracked the increase in production volumes over the same period.

It is anticipated that production expenses per boe for the remainder of 2017 will decrease to the $11.00/boe to $11.25/boe range. The Company expects reduced production costs on a per boe basis in the fourth quarter due to a full quarter impact related to the oil battery expansion and installation of water handling facilities in the Veteran area that has reduced water trucking and disposal costs.

Operating Netback

	Three months ended September 30,			Nine months ended September 30,		
($/boe)	**2017**	2016	% change	**2017**	2016	% change
Average realized sales	**$33.83**	$31.82	6	**$36.85**	$27.72	33
Royalty expenses	**(3.73)**	(2.24)	67	**(3.94)**	(1.85)	113
Production expenses	**(11.26)**	(11.58)	(3)	**(11.51)**	(11.43)	1
Operating field netback	**18.84**	18.00	5	**21.40**	14.44	48
Realized commodity hedging gain (loss)	**2.11**	2.10	–	**0.46**	4.56	(90)
Operating netback	**$20.95**	$20.10	4	**$21.86**	$19.00	15

The Company's operating netback for the third quarter of 2017 decreased 4% to $20.95/boe compared to $21.90/boe during the second quarter of 2017. This is attributable to a 46% decrease in natural gas prices ($1.62/mcf versus $3.01/mcf) and a 3% decrease in oil and natural gas liquids prices ($50.29/bbl versus $51.77/bbl), partially offset by a realized hedging gain in the third quarter of 2017 compared to a realized hedging loss in the second quarter of 2017 (realized gain of $2.11/boe versus realized loss of $0.19/boe) and a 5% decrease in production expense per boe ($11.26/boe versus $11.85/boe).

Third quarter 2017 operating netbacks were 4% higher than the $20.10/boe generated in the third quarter of 2016. This is attributable to a 16% increase in oil weighting (to 52% from 45%) an 11% increase in oil and natural gas liquids prices ($50.29/bbl versus $45.29/bbl) and a 3% decrease in production expense per boe ($11.26/boe versus $11.58/boe). The increase was partially offset by a 36% decrease in natural gas prices ($1.62/mcf versus $2.54/mcf) and a 67% increase in royalty expense per boe ($3.73/boe versus $2.24/boe).

During the first nine months of 2017, operating netbacks were 15% higher at $21.86/boe as compared to $19.00/boe generated for the same period in 2016. This is attributable to a 18% increase in oil weighting (to 52% from 44%), a 29% increase in oil and natural gas liquids prices ($52.41/bbl versus $40.64/bbl) and a 19% increase in natural gas prices ($2.48/mcf versus $2.08/mcf). These increases were partially offset by a lower realized hedging gain during the first nine months of 2017 compared to the same period in 2016 (realized gain of $0.46/boe versus realized gain of $4.56/boe) and a 113% increase in royalty expense per boe ($3.94/boe versus $1.85/boe).

General and Administrative ("G&A") Expenses

	Three months ended September 30,			Nine months ended September 30,		
($ thousands, except per boe)	**2017**	2016	% change	**2017**	2016	% change
Gross G&A costs	**$3,889**	$2,372	64	**$11,550**	$6,970	66
Capitalized costs and recoveries	**(832)**	(500)	66	**(2,503)**	(1,565)	60
Net G&A costs	**$3,057**	$1,872	63	**$9,047**	$5,405	67
Net G&A ($/boe)	**$1.62**	$1.89	(14)	**$1.72**	$1.98	(13)

Gross general and administrative ("G&A") expenses for both the third and second quarter of 2017 were $3.9 million. Net G&A costs of $1.62/boe in the third quarter of 2017 were 7% lower than the $1.74/boe in the second quarter of 2017, due to a 6% increase in production. Tamarack expects net G&A costs per boe to remain in the $1.55/boe to $1.65/boe range for the remainder of the year.

Gross G&A costs increased in the three months ended September 30, 2017, as compared to the same period in 2016, due to the increase in the number of employees and required office space as a result of the Viking Acquisition and a 90% increase in production. Net G&A costs of $1.62/boe in the third quarter of 2017 were 14% lower than the $1.89/boe in the same period of 2016.

For the first nine months of 2017, gross G&A costs were 66% higher at $11.6 million compared to gross costs of $7.0 million in the same period of 2016, due to the increase in the number of employees and required office space as a result of the Viking Acquisition and a 93% increase in production. Net G&A costs of $1.72/boe during the first nine months of 2017 were 13% lower than the $1.98/boe in the same period of 2016.

Stock-Based Compensation Expenses

Stock-based compensation expenses relating to stock options ("options") and restricted share awards ("RSU's") were $1.1 million and $3.2 million for the three and nine months ended September 30, 2017, respectively, compared to $0.8 million and $2.7 million for the same periods in 2016. Stock-based compensation was higher for the three and nine months ended September 30, 2017, due to the increased number of employees that were granted options and RSU's during the fourth quarter of 2016, as a result of the Viking Acquisition. Stock-based compensation expense is calculated based on graded vesting periods that are front-end loaded.

The Company capitalized $0.5 million and $1.5 million of stock-based compensation relating to exploration and development activities for the three and nine months ended September 30, 2017, compared to capitalizing $0.3 million and $1.1 million for the same periods in 2016.

For the nine months ended September 30, 2017, the Company issued 140,000 options at a weighted average exercise price of $3.01 per share and issued 267,275 RSU's to new employees.

Interest

Interest expense was $1.8 million and $5.0 million for the three and nine months ended September 30, 2017, respectively, compared to $0.9 million and $2.8 million for the same periods in 2016. The Company had $162.2 million drawn on its revolving credit facility at September 30, 2017, compared to $48.6 million drawn at September 30, 2016 related to the Viking Acquisition and increased capital for associated drilling and completions activities in 2017. Interest expense was higher for the three and nine months ended September 30, 2017, compared to the same periods in 2016, due to an interest rate increase during the third quarter of 2017 and to a higher average amount drawn year over year on the revolving credit facility. The average amount drawn for the three and nine months ended September 30, 2017, was approximately $156.1 million and $142.7 million, respectively, compared to an average amount drawn of approximately $50.0 million and $57.7 million during the same periods in 2016.

Depletion, Depreciation, Amortization and Accretion

The Company depletes its property, plant and equipment based on its proved plus probable reserves. The carrying value of undeveloped land in exploration and evaluation assets is also amortized over its term to expiry, which is charged to depletion, depreciation, amortization and accretion expense ("DDA&A").

	Three months ended September 30,			Nine months ended September 30,		
($ thousands, except per boe)	**2017**	2016	% change	**2017**	2016	% change
Depletion and depreciation	**$38,746**	$16,905	129	**$106,293**	$46,979	126
Amortization of undeveloped leases	**197**	203	(3)	**590**	557	6
Accretion	**892**	496	80	**2,706**	1,169	131
Total	**$39,835**	$17,604	126	**$109,589**	$48,705	125
Depletion and depreciation ($/boe)	**$20.50**	$17.03	20	**$20.24**	$17.19	18
Amortization ($/boe)	**0.10**	0.20	(50)	**0.11**	0.20	(45)
Accretion ($/boe)	**0.47**	0.50	(6)	**0.52**	0.43	21
Total ($/boe)	**$21.07**	$17.73	19	**$20.87**	$17.82	17

For the third quarter of 2017, DDA&A expense was $21.07/boe compared to $20.91/boe in the second quarter of 2017. On an absolute basis, DDA&A expense was $39.8 million in the third quarter of 2017 compared to $36.8 million during the second quarter of 2017, related to the 6% increase in production and higher DDA&A expense on a per boe basis.

Third quarter 2017 DDA&A expense of $21.07/boe was higher relative to the $17.73/boe recorded for the same period in 2016. The increase in DDA&A rate was related to the Viking Acquisition assets having a higher DDA&A rate than Tamarack's legacy DDA&A rate. On an absolute basis, DDA&A expense of $39.8 million was 126% higher in the third quarter of 2017 compared to $17.6 million in the third quarter of 2016, due to a 90% increase in production and higher DDA&A expense on a per boe basis.

For the first nine months of 2017, DDA&A expense of $20.87/boe was higher relative to the $17.82/boe recorded for the same period in 2016. The increase is due to the Viking Acquisition assets having a higher DDA&A rate than Tamarack's legacy DDA&A rate. On an absolute basis, DDA&A expense of $109.6 million was 125% higher in the first nine months of 2017, compared to $48.7 million in the first nine months of 2016, due to a 93% increase in production and higher DDA&A expense on a per boe basis.

Income Taxes

The Company did not incur any cash tax expense in the three and nine months ended September 30, 2017, nor does it expect to pay any cash tax in 2017 or 2018 based on current commodity prices, forecast taxable income, existing tax pools and planned capital expenditures.

For the three and nine months ended September 30, 2017, deferred income tax recovery of $2.1 million and a deferred tax expense of $0.7 million, respectively, were recognized compared to a deferred income tax expense of $0.9 million and a deferred income tax recovery of $4.4 million for the same periods in 2016.

Funds from Operations and Net Loss

($ thousands)	Three months ended September 30, 2017	2016	% change	Nine months ended September 30, 2017	2016	% change
Petroleum and natural gas sales	**$63,927**	$31,588	102	**$193,512**	$75,724	156
Royalties	**(7,043)**	(2,220)	217	**(20,670)**	(5,049)	309
Realized gain on financial instruments	**3,994**	2,083	92	**2,422**	12,459	(81)
Production expenses	**(21,271)**	(11,494)	85	**(60,421)**	(31,241)	93
General and administration expenses	**(3,057)**	(1,872)	63	**(9,047)**	(5,405)	67
Interest	**(1,776)**	(913)	95	**(4,996)**	(2,777)	80
Funds from operations (excluding transaction costs)	**$34,774**	$17,172	103	**$100,800**	$43,711	131

Funds from operations during the third quarter of 2017 were $34.8 million ($0.15 per share basic and diluted) compared to $33.7 million ($0.15 per share basic and diluted) in the second quarter of 2017. The increase in the absolute amount is primarily the result of a 6% increase in production and a realized hedging gain in the third quarter of 2017 compared to a realized hedging loss in the second quarter of 2017. These increases were partially offset by a 46% decrease in natural gas prices and a 3% decrease in crude oil and natural gas liquids pricing.

Third quarter 2017 funds from operations were higher on an absolute basis than the same period in 2016 which totaled $17.2 million ($0.13 per share basic and diluted), primarily due to a 90% increase in production, an 11% increase in crude oil and natural gas liquids pricing and a higher realized hedging gain in the third quarter of 2017 compared to the same quarter of 2016. The year over year increase was partially offset by a 36% decrease in natural gas price, a 217% increase in royalty expense, an 85% increase in production expense, a 95% increase in interest expense and a 63% increase in G&A expense.

Funds from operations excluding transaction costs during the first nine months of 2017 were $100.8 million ($0.45 per share basic and diluted) compared to $43.7 million ($0.37 per share basic and diluted) during the same period in 2016. The increase is primarily due to a 93% increase in production, a 29% increase in crude oil and natural gas liquids pricing and a 19% increase in natural gas pricing. The year-over-year increase was partially offset by a 309% increase in royalty expense, a 93% increase in production expense, an 80% increase in interest expense, a 67% increase in G&A expense and a lower realized hedging gain in the first nine months of 2017 compared to the same period in 2016.

($/boe)	Three months ended September 30, 2017	2016	% change	Nine months ended September 30, 2017	2016	% change
Petroleum and natural gas sales	**$33.83**	$31.82	6	**$36.85**	$27.72	33
Royalties	**(3.73)**	(2.24)	67	**(3.94)**	(1.85)	113
Realized gain on financial instruments	**2.11**	2.10	–	**0.46**	4.56	(90)
Production expenses	**(11.26)**	(11.58)	(3)	**(11.51)**	(11.43)	1
General and administration expenses	**(1.62)**	(1.89)	(14)	**(1.72)**	(1.98)	(13)
Interest	**(0.94)**	(0.92)	2	**(0.95)**	(1.02)	(7)
Funds from operations (excluding transaction costs)	**$18.39**	$17.29	6	**$19.19**	$16.00	20

On a per boe basis, third quarter 2017 funds from operations decreased 4% to $18.39/boe from $19.14/boe in the second quarter of 2017. The decrease is due to 46% lower natural gas pricing and 3% lower crude oil and natural gas liquids prices, partially offset by a 6% decrease in royalty expense per boe, a 5% decrease in production expense per boe and a realized hedging gain in the third quarter of 2017 compared to a realized hedging loss in the second quarter of 2017.

Compared to funds from operations of $17.29/boe realized in the third quarter of 2016, funds from operations per boe in the third quarter of 2017 were 6% higher. The increase is due to an 11% increase in crude oil and natural gas liquids prices, a 14% decrease in G&A expense per boe and a 3% decrease in production expense per boe, partially offset by a 36% decrease in natural gas prices and a 67% increase in royalty expense per boe.

On a per boe basis, funds from operations excluding transaction costs for the first nine months of 2017 increased 20% to $19.19/boe from $16.00/boe in the first nine months of 2016. The increase is due to a 29% increase in crude oil and natural gas liquids prices, a 19% increase in the natural gas price and a 13% decrease in G&A expense per boe. This increase was partially offset by a 113% increase in royalty expense per boe and a 90% decrease in the realized hedging gain per boe during the first nine months of 2017 compared to the first nine months of 2016.

The Company recorded a net loss of $6.7 million ($0.03 per share basic and diluted) during the three months ended September 30, 2017, compared to net income of $3.1 million ($0.01 per share basic and diluted) for the previous quarter. The factors contributing to a net loss in the third quarter of 2017 compared to net income in the previous quarter included a third quarter unrealized hedging loss that partially reversed a second quarter unrealized hedging gain caused by changes in commodity prices and higher DDA&A expense. These factors were partially offset by a realized hedging gain recorded in the third quarter compared to a realized hedging loss during the second quarter.

The Company recorded a net loss of $6.7 million ($0.03 per share basic and diluted) during the three months ended September 30, 2017, compared to a net loss of $3.2 million ($0.02 per share basic and diluted) for the same period in 2016. The factors contributing to a higher net loss in the third quarter of 2017 compared to the same period in 2016 include higher expenses for production, royalties, G&A and DDA&A, partially offset by higher oil and natural gas revenue.

The Company recorded a net loss of $1.4 million ($0.01 per share basic and diluted) during the nine months ended September 30, 2017, compared to a net loss of $19.4 million ($0.17 per share basic and diluted) for the same period in 2016. The factors contributing to a lower net loss in the first nine months of 2017 compared to the same period in 2016 include higher oil and natural gas revenue and an unrealized gain on financial instruments compared to an unrealized loss in the first nine months of 2016. These were partially offset by $5.7 million in transaction costs related to the Viking Acquisition in the first quarter of 2017, a lower realized hedging gain, and higher expenses for production, royalties, G&A, interest and DDA&A.

Capital Expenditures (Including Exploration and Evaluation Expenditures)

The following table summarizes capital spending, excluding non–cash items:

($ thousand)	Three months ended September 30, 2017	2016	% change	Nine months ended September 30, 2017	2016	% change
Land	**$610**	$311	96	**$1,882**	$1,489	26
Geological and geophysical	**–**	24	(100)	**2,022**	437	363
Drilling and completion	**58,105**	13,290	337	**117,424**	34,110	244
Equipment and facilities	**14,643**	592	2,373	**33,175**	4,858	583
Capitalized G&A	**661**	180	267	**1,983**	707	180
Office equipment	**44**	100	(56)	**300**	355	(15)
Total capital expenditures	**$74,063**	$14,497	411	**$156,786**	$41,956	274

Aided by continual access to service providers, particularly pressure pumpers, and dry conditions that prevailed through most of the summer, Tamarack was able to successfully execute the majority of its planned second half capital program during the third quarter of 2017. The Company spent a total of $74.1 million in the period, close to its second half 2017 guidance range of $80 to $90 million, which is a significant increase over its second quarter program of $19.0 million that reflected the impact of spring break-up conditions. During the third quarter of 2017, the Company drilled, completed and equipped 40 (38.6 net) Viking oil wells, five (5.0 net) Cardium oil wells, one (0.8 net) Ellerslie oil well and one (1.0 net) Mannville gas well. The Company also drilled ten (10.0 net) Viking oil wells, three (3.0 net) Cardium oil wells and two (2.0 net) heavy oil wells, which were completed and brought on production subsequent to quarter end. Additionally, the Company spudded one (1.0 net) Baron Sands oil well in Penny, which is expected to come on-stream in the fourth quarter of 2017.

To position Tamarack for a strong start to 2018, continue capitalizing on the operational momentum realized during the third quarter, and avoid any potential challenges accessing services in the first quarter of 2018, the Company decided to accelerate $10-15 million of first quarter 2018 capital into the fourth quarter 2017 program. With this accelerated capital, Tamarack plans to drill 13 wells in Veteran and one Cardium well in Wilson Creek. As a result of both the acceleration and recent successful tuck-in acquisitions, Tamarack's full year 2017 capital budget has been increased to $195-198 million, including the infrastructure investment at Veteran as well as the additional drilling capital in the fourth quarter of 2017.

In addition to the Company's significant drilling and completion projects, Tamarack advanced several other capital activities during the third quarter designed to reduce costs and enhance the asset base. In Veteran, the Company concluded the oil battery expansion and installation of associated oil pipelines, which collectively, are expected to significantly reduce trucking costs for the area, while in Wilson Creek, the purchase of a compressor will eliminate ongoing expenses associated with renting compression equipment.

2017 Drilling Summary (including wells spudded by September 30, 2017)		
	Gross	Net
Heavy Oil	5.0	5.0
Viking	89.0	84.6
Mannville	3.0	3.0
Cardium	15.0	14.3
Other	2.0	1.8
	114.0	108.7

The Company's net undeveloped land totaled 408,856 acres at the end of the third quarter of 2017.

Acquisitions

During the three and nine months ended September 30, 2017, costs of $3.0 million (net of dispositions of $0.4 million) and $80.3 million, respectively, were incurred related to corporate and property acquisitions. The Viking Acquisition accounted for $0.3 million during the third quarter and $2.7 million was related to a tuck-in acquisition in Penny.

The Viking Acquisition has been accounted for as a business combination using the acquisition method of accounting, whereby the assets acquired and the liabilities assumed are recorded at the estimated fair value on the acquisition date of January 11, 2017. The allocation of the purchase price, based on management's estimate of fair values, is outlined in the table below:

Consideration (thousands):		
Cash consideration	$	57,972
Share consideration (90,142,906 common shares)		310,092
Total consideration	$	368,064
Net Assets Acquired (thousands):		
Current assets	$	39,684
Current liabilities		(10,517)
Risk management contracts		(269)
Bank debt		(47,115)
Property, plant and equipment		480,417
Decommissioning obligations		(19,207)
Deferred tax liability		(74,929)
Net assets	$	368,064

The fair value of property, plant and equipment has been estimated with reference to an independently prepared reserves evaluation for the acquired properties. The fair value of decommissioning obligations was initially estimated using a credit-adjusted risk-free rate of 8% and subsequently revalued using the risk-free rate.

Subsequent to the quarter end, a $5.5 million complementary tuck-in land acquisition was completed in the Viking area of Alberta, which further enhances the Company's land base and drilling location inventory.

Liquidity and Capital Resources

Tamarack's net debt, including working capital deficiency but excluding the fair value of financial instruments, totaled $194.9 million as at September 30, 2017. This compares to the previous quarter and the third quarter of 2016, which recorded net debt of $152.4 million and $62.8 million, respectively. Tamarack's third quarter 2017 net debt to annualized funds from operations was 1.4 times compared to 1.1 times as at the second quarter 2017, which is related to timing of investment and reflects the Company's decision to accelerate its second half 2017 capital program during the third quarter. As production volumes associated with the expanded third quarter drilling program come on-stream in the fourth quarter, Tamarack anticipates that its Q4 2017 exit net debt to annualized funds from operations ratio will return to approximately 1.0 times, assuming current strip prices.

At September 30, 2017, Tamarack had 227,693,382 common shares, 5,467,051 options and 3,307,441 RSUs outstanding. At November 7, 2017, there were 227,653,382 common shares, 5,467,051 options and 3,307,441 RSUs outstanding. This compares to December 31, 2016, at which time there were 137,527,475 common shares, 5,327,051 options and 3,063,167 RSUs outstanding. The Company had 227,691,425 and 224,376,019 weighted average basic common shares outstanding during the three and nine months ended September 30, 2017. No preferred shares of Tamarack are issued and outstanding.

On January 11, 2017, the Company issued 90,142,906 common shares on closing of the Viking Acquisition.

On December 29, 2016, the Company issued 500,000 flow-through common shares, related to Canadian exploration expenditures, at $5.00 per share for total gross proceeds of $2.5 million. Under the terms of the flow-through share agreements, the Company is required to incur the expenditures by December 31, 2017. As of September 30, 2017, the Company had incurred the full $2.5 million of qualifying expenditures.

At September 30, 2017, and December 31, 2016, there were 1,155,007 preferred shares of Tamarack Acquisition Corp. ("TAC Preferred Shares") which are exchangeable into 1,110,584 common shares of the Company. The TAC Preferred Shares are fully vested at September 30, 2017, and are exchangeable into common shares of Tamarack at an exchange price of $3.12 per common share. An exchange of the TAC Preferred Shares is at the election of the Company under certain circumstances.

The Company currently has a revolving credit facility in the amount of $245 million and a $20 million operating facility (collectively the "Facility") with a syndicate of lenders. The Facility totals $265 million, lasts for a 364 day period and will be subject to its next 364 day extension by May 25, 2018. If not extended on May 25, 2018, the Facility will cease to revolve and all outstanding balances will become repayable in one year from that extension date on May 25, 2019.

The interest rate on the Facility is determined through a pricing grid that categorizes based on a net debt to cash flow ratio. The interest rate will vary from a low of the bank's prime rate plus 1.0% to a high of the bank's prime rate plus 2.5%. The standby fee for the Facility will vary as per a pricing grid from a low of 0.5% to a high of 0.875% on the undrawn portion of the Facility. The Facility has been secured by a $550 million supplemental debenture with a floating charge over all assets. As the available lending limits of the two facilities are based on the bank's interpretation of the Company's reserves and future commodity prices, there can be no assurance as to the amount of available facilities that will be determined at each scheduled review. Subsequent to the quarter, the lending review commenced and management expects an increase to $290 million from $265 million by December 31, 2017.

With continued commodity price volatility impacting the oil and gas industry, Tamarack's strategy remains focused on preserving balance sheet strength by adjusting capital spending as appropriate to respond to changes in commodity prices. Tamarack intends to maintain balance sheet flexibility which allows the Company to be opportunistic and take advantage of potential opportunities within core areas while commodity prices are lower. The Viking Acquisition that closed on January 11, 2017, and the tuck-in acquisitions completed during the third and fourth quarters of 2017 are consistent with this approach. Further, the Company remains committed to executing its proven strategy of focusing on drilling wells that target a return on capital cost payout of 1.5 years or less, and will continue to control or reduce capital and production costs where possible to optimize capital efficiencies.

2017 Guidance

Tamarack's 2017 capital program and associated guidance is designed to meet the objective of maintaining a strong and flexible balance sheet in the context of a volatile commodity price environment while delivering debt-adjusted per share growth in production and funds from operations. The Company's key 2017 guidance is summarized in the following table:

	2017 Guidance:
Average annual production (boe/d)	19,000 - 20,000
Liquids weighting (%)	~55 - 60
Exit production (boe/d)	~22,000
Liquids weighting (%)	~57 - 62
Annual capital expenditure range ($millions)	$195 to $198
Second half 2017 capex ($millions)	$112 to $115
Year end 2017 net debt to Q4 annualized funds from operations ratio *(including hedges)*	~1.0 times
Liquidity on existing credit facilities ($millions)	$95 - $105
Second half 2017 price assumptions:	
WTI ($US/bbl)	$48.50
Edmonton Par ($/bbl)	$58.40
AECO ($/GJ)	$2.25
Canadian/US dollar exchange rate	$0.79

Given Tamarack's decision to capitalize on operational efficiencies and accelerate its second half 2017 capital program during the third quarter, the Company's third quarter 2017 net debt to annualized funds from operations was 1.4 times compared to 1.1 times as at the second quarter 2017. This increased ratio relates to timing of investment but as production volumes associated with the expanded third quarter drilling program come on-stream in the fourth quarter, Tamarack anticipates that its Q4 2017 exit net debt to annualized funds from operations ratio will return to approximately 1.0 times, assuming current strip prices. Tamarack's top priority is to maintain a strong balance sheet which affords the flexibility to capitalize on opportunities that may arise to further add to its high-quality drilling inventory. The Company will continue to closely monitor current and future commodity prices and has the ability to accelerate or reduce capital expenditures in accordance with price fluctuations from current levels.

Commitments

The following table summarizes the Company's commitments as at September 30, 2017:

($ thousands)	2017	2018	2019	2020	2021	2022	2023
Office lease	159	542	542	263	–	–	–
Take or pay commitments[(1)]	247	986	–	–	–	–	–
Rental fee[(2)]	1,293	5,170	5,170	5,170	5,170	3,299	714
Total	1,699	6,698	5,712	5,433	5,170	3,299	714

(1) Pipeline commitment to deliver a minimum of 300 m3/d of crude oil/condensate subject to a take-or-pay provision of $9.00/m3. The remaining term is 15 months.

(2) Rental fee of $0.3 million per month for a maximum period of 90 months starting in January 2015 relating to four facilities and rental fee of $0.1 million per month for a maximum period of 90 months starting in January 2016 relating to four facilities.

Unit Cost Calculation

For the purpose of calculating unit costs, natural gas volumes have been converted to a barrel of oil equivalent ("boe") using six thousand cubic feet equal to one barrel, unless otherwise stated. A boe conversion ratio of 6:1 is based upon an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion conforms to the Canadian Securities Regulators National Instrument 51–101 *Standards of Disclosure for Oil and Gas Activities*. Boe may be misleading, particularly if used in isolation.

Abbreviations

Crude Oil		Natural Gas	
Bbl	barrel	AECO	natural gas storage facility located at Suffield, AB
bbl/d	barrels per day	GJ	Gigajoule
WTI	West Texas Intermediate	mcf	thousand cubic feet
		mcf/d	thousand cubic feet per day

Other	
Boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
NGL	natural gas liquids

Non–IFRS and Additional IFRS Measures

This document contains "funds from operations", which is an additional IFRS measure presented in the consolidated financial statements. The Company uses funds from operations as a key measure to demonstrate the Company's ability to generate funds to repay debt and fund future capital investment. This document also contains the terms "net debt" and "netbacks", which are non-IFRS financial measures. The Company uses these measures to help evaluate its performance. These non-IFRS financial measures do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures presented by other issuers. The Company uses net debt (bank debt plus working capital deficiency and excluding fair value of financial instruments) as an alternative measure of outstanding debt. The Company considers corporate netbacks a key measure as it demonstrates corporate profitability relative to current commodity prices. Netbacks, which have no

IFRS equivalent, are calculated on a per boe basis by deducting royalties and production costs from petroleum and natural gas sales, including realized gains and losses on commodity derivative contracts.

(a) **Funds from Operations -** Tamarack's method of calculating funds from operations may differ from other companies, and therefore may not be comparable to measures used by other companies. Tamarack calculates funds from operations as cash flow from operating activities, as determined under IFRS, before the changes in non-cash working capital related to operating activities and abandonment expenditures and before transaction costs related to acquisitions or dispositions that are not part of regular ongoing operations. The Company believes the uncertainty surrounding the timing of collection, payment or incurrence of these items makes them less useful in evaluating Tamarack's operating performance. Tamarack uses funds from operations as a key measure to demonstrate the Company's ability to generate funds to repay debt and fund future capital investment. Funds from operations per share have been calculated using the same basic and diluted weighted average share amounts used in earnings per share calculations.

A summary of this reconciliation is presented as follows:

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	**2017**	2016	**2017**	2016
Cash provided by operating activities	**$35,237**	$14,085	**$94,469**	$43,127
Abandonment expenditures	**314**	2	**675**	187
Transaction costs	**–**	500	**5,663**	596
Changes in non-cash working capital	**(777)**	2,585	**(7)**	(199)
Funds from operations	**$34,774**	$17,172	**$100,800**	$43,711
Funds from operation per share - basic	**$ 0.15**	$ 0.13	**$ 0.45**	$ 0.37
Funds from operation per share - diluted	**$ 0.15**	$ 0.13	**$ 0.45**	$ 0.37

(b) **Operating Netback -** Management uses certain industry benchmarks, such as operating netback, to analyze financial and operating performance. This benchmark does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. Operating netback equals total petroleum and natural gas sales, including realized gains and losses on commodity derivative contracts, less royalties and production costs calculated on a per boe basis. Management considers operating netback an important measure to evaluate its operational performance, as it demonstrates field level profitability relative to current commodity prices. The calculation of the Company's netbacks can be seen on page 7 in the section titled "Operating Netback."

(c) **Net Debt -** Tamarack closely monitors its capital structure with a goal of maintaining a strong balance sheet to fund the future growth of the Company. The Company monitors net debt as part of its capital structure. Net debt does not have a standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. Management considers net debt an important measure to assist in providing a more complete understanding of cash liabilities.

The following outlines the Company's calculation of net debt (excluding the effect of derivative contracts):

($ thousand)	September 30, 2017	December 31, 2016
Bank debt	$162,164	$45,227
Accounts payable and accrued liabilities	59,774	25,015
Accounts receivable	(26,776)	(16,557)
Prepaid expenses and deposits	(245)	(1,369)
Net debt	$194,917	$52,316

Selected Quarterly Information

Three months ended	**Sep. 30, 2017**	Jun. 30, 2017	Mar. 31, 2017	Dec. 31, 2016	Sep. 30, 2016	Jun. 30, 2016	Mar. 31, 2016	Dec. 31, 2015
Sales volumes								
Natural gas *(mcf/d)*	**49,987**	47,696	45,852	31,226	29,007	27,462	25,818	23,229
Oil and NGL's *(bbls/d)*	**12,210**	11,387	10,154	6,249	5,955	4,959	5,279	6,096
Average boe/d *(6:1)*	**20,541**	19,336	17,796	11,453	10,790	9,536	9,582	9,968
Product prices								
Natural gas *($/mcf)*	**1.62**	3.01	2.89	3.27	2.54	1.62	2.03	2.66
Oil and NGL's *($/bbl)*	**50.29**	51.77	55.74	52.88	45.29	45.35	30.90	39.30
Oil equivalent *($/boe)*	**33.83**	37.91	39.25	37.76	31.82	28.25	22.50	30.23
(000s, except per share amounts)								
Financial results								
Gross revenues	**63,927**	66,715	62,870	39,793	31,588	24,517	19,619	27,725
Cash provided by operating activities	**35,237**	34,537	24,695	17,610	14,085	14,560	14,483	23,449
Funds from operations	**34,774**	33,670	26,693	20,453	16,672	15,364	11,078	18,615
Per share – basic	**0.15**	0.15	0.12	0.15	0.12	0.13	0.11	0.19
Per share – diluted	**0.15**	0.15	0.12	0.15	0.12	0.13	0.11	0.18
Net income (loss)	**(6,742)**	3,053	2,290	(8,424)	(3,196)	(10,368)	(5,835)	5,119
Per share – basic	**(0.03)**	0.01	0.02	(0.06)	(0.02)	(0.09)	(0.06)	0.05
Per share – diluted	**(0.03)**	0.01	0.02	(0.06)	(0.02)	(0.09)	(0.06)	0.05
Additions to property and equipment	**74,063**	19,002	63,721	12,665	14,497	10,309	17,149	8,743
Net acquisitions	**2,962**	1,301	75,995	(248)	85,308	–	–	2,075
Total assets	**1,206,886**	1,178,404	1,186,285	663,564	679,259	542,917	553,135	549,068
Net debt[1]	**(194,917)**	(152,354)	(165,561)	(52,316)	(62,817)	(57,791)	(62,696)	(97,941)
Bank debt	**162,164**	140,795	135,484	45,227	48,598	48,630	50,056	82,822
Decommissioning obligations	**167,102**	171,909	164,012	112,115	122,810	68,149	65,643	63,331

(1) Refer to definition of net debt under "Non IFRS Measures"

Significant factors and trends that have impacted the Company's results during the above periods include:

- The volatility in commodity prices and the resultant effect on revenue, cash provided by operating activities and net income (loss).
- The Company uses derivative contracts to reduce the financial impact of volatile commodity prices which can cause significant fluctuations in net income (loss) due to unrealized gains and losses recognized on a quarterly basis.

- On January 11, 2017, Tamarack closed the Viking Acquisition which added assets in Southeast Alberta and Southwest Saskatchewan; in the first nine months of 2017 this acquisition added $46.8 million to oil and natural gas revenue and contributed $3.6 million to net loss.
- During the third quarter of 2016, Tamarack closed two strategic acquisitions, including certain assets in the Penny area of Southern Alberta and the consolidation of assets in the Redwater and Wilson Creek areas of Alberta (the "Penny and Redwater Acquisitions") on July 12, 2016 and July 25, 2016, respectively; in 2016 these acquisitions added $6.3 million to oil and natural gas revenue and contributed $0.5 million to net loss.
- The Company recorded $5.7 million in transaction costs in the first quarter of 2017 related to the Viking Acquisition and $0.5 million in transaction costs in the third quarter of 2016 related to the Penny and Redwater Acquisitions.

Critical Accounting Estimates

Management is required to make judgments, assumptions, and estimates in applying its accounting policies which have significant impact on the financial results of the Company. The following outlines the accounting policies involving the use of estimates that are critical to understanding the financial condition and results of operations of the Company:

(a) **Oil and natural gas reserves** – Oil and natural gas reserves, as defined by the Canadian Securities Administrators in National Instrument 51-101 with reference to the Canadian Oil and Gas Evaluation Handbook, are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

An independent reserve evaluator using all available geological and reservoir data, as well as historical production data, has prepared the Company's oil and natural gas reserve estimates. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in the Company's development plans.

(b) **Exploration and evaluation assets –** The costs of drilling exploratory wells are initially capitalized as exploration and evaluation ("E&E") assets pending the evaluation of commercial reserves. Commercial reserves are defined as the existence of proved and probable reserves which are determined to be technically feasible and commercially viable to extract. Reserves may be considered commercially producible if management has the intention of developing and producing them based on factors such as project economics, quantities of reserves, expected production techniques, estimated production costs and capital expenditures.

(c) **Carrying Value of Property, Plant & Equipment** – Property, plant and equipment is measured at cost less accumulated depletion, depreciation, amortization and impairment losses. The net carrying value of property, plant and equipment and estimated future development costs is depleted using the unit-of-production method based on estimated proved and probable reserves. Changes in estimated proved and probable reserves or future development costs have a direct impact on the calculation of depletion expense.

The Company is required to use judgment when designating the nature of oil and gas activities as exploration and evaluation assets or development and production assets within property, plant and equipment. Exploration and evaluation assets and development and production assets are aggregated into Cash Generating Units ("CGUs") based on their ability to generate largely independent cash flows. The allocation of the Company's assets into CGUs requires significant judgment with respect to use of shared infrastructure, existence of active markets for the Company's products and the way in which management monitors operations.

E&E expenditures relating to activities to explore and evaluate oil and natural gas properties are initially capitalized and include costs associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and testing, directly attributable overhead and administration expenses, and costs associated with retiring the assets. E&E assets are carried forward until technical feasibility and commercial viability of extracting a mineral resource is determined, which is considered to be when proved and/or probable reserves are determined to exist. E&E assets are tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of CGUs, aggregated at the segment level. The determination of the fair value of CGUs requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices and development and operating costs. Changes in any of these assumptions, such as a downward revision in reserves, decrease in commodity prices or increase in costs, could impact the fair value.

The Company assesses property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. If any such indication of impairment exists, the Company performs an impairment test related to the specific CGU. The determination of fair value of CGUs requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices and development and operating costs. Changes in any of these assumptions, such as a downward revision in reserves, decrease in commodity prices or increase in costs, could impact the fair value.

(d) **Decommissioning obligations –** The decommissioning obligations are estimated based on existing laws, contracts or other policies. The fair value of the obligation is based on estimated future costs for abandonments and reclamations discounted at a risk-free rate. The costs are included in property, plant and equipment and amortized over its useful life. The liability is adjusted each reporting period to reflect the passage of time, with the accretion expense charged to net earnings, and for revisions to the estimated future cash flows. By their nature, these estimates are subject to measurement uncertainty and the impact on the consolidated financial statements could be material.

(e) **Stock-based compensation –** The Company uses the fair value method for valuing stock option grants. Under this method, compensation cost attributable to all stock options granted is measured at fair value at the grant date and expensed over the vesting period. The Black-Scholes option pricing model is used to estimate the fair value of the stock options and it contains such estimates as expected share price volatility and the Company's risk-free interest rate. Any changes in these assumptions could alter the fair value and net earnings.

(f) **Income taxes** – The determination of income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

(g) **Financial instruments** – The Company utilizes financial instruments to manage the exposure to market risks relating to commodity prices. Fair values of derivative contracts fluctuate depending on the underlying estimate of future commodity prices and foreign currency exchange rates.

Future Accounting Pronouncements

The Company has reviewed new and revised accounting pronouncements listed below that have been issued, but are not yet effective. There are no other standards or interpretations issued, but not yet adopted, that are anticipated to have a material effect on the reported loss or net assets of the Company.

In July 2014, the International Accounting Standards Board ("IASB") completed the final elements of IFRS 9 "Financial Instruments." The Standard supersedes earlier versions of IFRS 9 and completes the IASB's project to replace IAS 39 "Financial Instruments: Recognition and Measurement." IFRS 9, as amended, includes a principle-based approach for classification and measurement of financial assets, a single 'expected loss' impairment model and a substantially-reformed approach to hedge accounting. The mandatory effective date of IFRS 9 is for annual periods on or after January 1, 2018, and must be applied retrospectively with some exceptions. Early adoption is permitted. The Company is evaluating the impact of this standard on the financial statements and does not anticipate a material change to the valuation of its financial assets.

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers", which replaces IAS 18 "Revenue", IAS 11 "Construction Contracts" and related interpretations. In July 2015, the IASB issued an amendment to IFRS 15, deferring the effective date by one year. IFRS 15 provides clarification for recognizing revenue from contracts with customers and establishes a single revenue recognition and measurement framework. The standard is required to be adopted either retrospectively or using a modified transition approach for fiscal years beginning on or after January 1, 2018, with earlier adoption permitted. The Company is evaluating the impact of this standard on the financial statements and does not anticipate it to have a material impact.

In January 2016, the IASB issued IFRS 16 "Leases". The new standard is effective for annual periods beginning on or after January 1, 2019. Earlier application is permitted for entities that apply IFRS 15 "Revenue from Contracts with Customers" at or before the date of initial adoption of IFRS 16. IFRS 16 will replace IAS 17 "Leases". This standard introduces a single lessee accounting model and requires a lessee to recognize assets and liabilities for all leases with a term of more than 12 months, unless the underlying asset is of low value. A lessee is required to recognize a right-of-use asset representing its right to use the underlying asset and a lease liability representing its obligation to make lease payments. The Company is evaluating the impact of the standard on the Company's financial statements.

Disclosure Controls and Internal Controls Over Financial Reporting

The Company has designed disclosure controls and procedures ("DCP") to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

The Company has designed internal controls over financial reporting ("ICFR") to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company is required to disclose herein any change in the Company's ICFR that occurred during the recent fiscal period that has materially affected, or is reasonably likely to materially affect, the Company's ICFR.

No material changes in the Company's DCP and its ICFR were identified during the quarter ended September 30, 2017 that have materially affected, or are reasonably likely to materially affect, the

Company's internal controls over financial reporting.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Business Risks

Tamarack faces business risks, both known and unknown, with respect to its oil and gas exploration, development, and production activities that could cause actual results or events to differ materially from those forecast. Most of these risks (financial, operational or regulatory) are not within the Company’s control. While the following sections discuss some of these risks, they should not be construed as exhaustive.

Financial Risks

Financial risks include commodity pricing; exchange and interest rates; and volatile markets.

Commodity price fluctuations result from market forces completely out of the Company’s control and can significantly affect the Company’s financial results. In addition, fluctuations between the Canadian dollar and the US dollar can also have a significant impact. Expenses are all incurred in Canadian dollars while crude oil, and to some extent natural gas, prices are based on reference prices denominated in US dollars. As a result of both of these factors, Tamarack may enter into derivative instruments to partially mitigate the effects of downward price volatility. To evaluate the need for hedging, management, with direction from the Board of Directors, monitors future pricing trends together with the cash flow necessary to fulfill capital expenditure requirements. Tamarack will only enter into a hedge to reduce downside uncertainty of pricing, not as a speculative venture.

Operational Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of Tamarack depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, existing reserves and their subsequent production will decline over time as they are exploited. A future increase in Tamarack’s reserves will depend not only on its ability to explore and develop any properties it may have, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that further commercial quantities of oil and natural gas will be discovered or acquired by Tamarack.

Tamarack endeavors to mitigate these risks by, among other things, ensuring that its employees are highly qualified and motivated. Prior to initiating capital projects, the Tamarack technical team completes an economic analysis, which attempts to reflect the risks involved in successfully completing the project. In an effort to mitigate the risk of not finding new reserves, or of finding reserves that are not economically viable, Tamarack utilizes various technical tools, such as 2D and 3D seismic data, rock sample analysis and the latest drilling and completions technology.

Insurance is in place to protect against major asset destruction or business interruption, including well blow-outs and pollution. In addition, Tamarack cultivates relationships with its suppliers in an effort to ensure good service regardless of the prevailing cycle of oil and gas activity.

Operational risk is mitigated by having Tamarack employees address the continued development of a new or established reservoir on a go-forward basis, using the same procedure that is used to address exploration risk. The decision to produce reserves is made based on the amount of capital required, production practices and reservoir quality. Tamarack evaluates reservoir development based on the timing, amount of additional capital required and the expected change in production values. Finding and development costs are controlled when capital is employed in a cost-effective manner.

Regulatory Risks

Regulatory risks include the possibility of changes to royalty, tax, environmental and safety legislation. Tamarack endeavours to anticipate the costs related to compliance and budget sensibly for them. Changes to environmental and safety legislation may also cause delays to Tamarack's drilling plans, its production efficiencies and may adversely affect its future earnings. Restrictive new legislation is a risk the Company cannot control.

Forward Looking Statements

Certain statements contained within this MD&A constitute forward-looking statements within the meaning of applicable Canadian securities legislation. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "budget", "plan", "endeavour", "continue", "estimate", "evaluate", "expect", "forecast", "monitor", "may", "will", "can", "able", "potential", "target", "intend", "consider", "focus", "identify", "use", "utilize", "manage", "maintain", "remain", "result", "cultivate", "could", "should", "believe" and similar expressions. The Company believes that the expectations reflected in such forward-looking statements are reasonable but no assurance can be given that such expectations will prove to be correct and such forward-looking statements should not be unduly relied upon.

Without limitation, this MD&A contains forward-looking statements pertaining to:

- the intentions of management and the Company;
- the availability, terms, use and renewal of credit facilities;
- estimated production rates in 2017;
- the timeframe for resumption of full-scale operations at the Coleville Plant;
- future production costs and G&A expenses;
- Tamarack's focus on preserving balance sheet strength by adjusting capital spending relative to commodity prices and reducing production costs on newly acquired assets;
- Tamarack's primary focus areas for production growth;
- tuck-in acquisitions in Tamarack's core areas;
- future drilling plans;
- deferred tax liabilities;
- expectations as to royalty rates as a percentage of revenue;
- future capital expenditures and capital program funding;
- estimated year end debt to funds from operations (including hedges) ratio;
- the Company's capital program and guidance for 2017 and 2018;
- derivative contracts and Tamarack's commodity price and foreign exchange rate risk management activities, including strategies to minimize exposure to Alberta gas market fluctuations;
- expectations as to oil and natural gas pricing in 2017, 2018 and beyond;
- expectations as to oil and natural gas weighting in 2017; and
- the ability of the Company to take advantage of opportunities that may arise in the low commodity price environment.

With respect to the forward-looking statements contained in this MD&A, Tamarack has made assumptions regarding, among other things:

- future commodity prices and the actual prices received for the Company's products;
- expected production costs and G&A expenses;
- estimated reserves of oil and natural gas;
- the ability to obtain equipment and services in the field in a timely and efficient manner;
- the ability to add production and reserves through acquisition and/or drilling at competitive prices;
- the timing of anticipated future production additions from the Company's properties and acquisitions;
- the realization of anticipated benefits of acquisitions, including the Penny and Redwater Acquisitions, the Viking Acquisition and the tuck-in acquisition at Penny, and drilling programs in relation thereto;
- drilling results, including field production rates and decline rates;
- the continued application of horizontal drilling and fracturing techniques and pad drilling;
- the continued availability of capital and skilled personnel;
- the ability to obtain financing on acceptable terms;
- the accuracy of Tamarack's geological interpretation of its drilling and land opportunities, including the ability of seismic activity to enhance such interpretation;
- the impact of increasing competition;
- the ability of the Company to secure adequate product transportation;
- the ability to enter into future commodity derivative contracts on acceptable terms; and
- the continuation of the current tax, royalty and regulatory regime.

Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results may differ materially from those currently anticipated or implied by such forward-looking statements due to a number of factors and risks. These include:

- the material uncertainties and risks described under the headings "Critical Accounting Estimates", "Future Accounting Pronouncements", "Disclosure Controls and Internal Controls Over Financial Reporting", "Business Risks", "Financial Risks", "Operational Risks" and "Regulatory Risks";
- the material assumptions and observations described under the headings "Production", "Petroleum, Natural Gas Sales and Royalties", "Production Expenses", "Operating Netback", "General and Administrative ("G&A") Expenses", "Stock-Based Compensation Expenses", "Interest", "Depletion, Depreciation, Amortization and Accretion", "Income Taxes", "Funds from Operations and Net Loss", "Capital Expenditures (Including Exploration and Evaluation Expenditures)", "Acquisitions", "Liquidity and Capital Resources", "2017 Guidance", "Commitments" and "Selected Quarterly Information";
- the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production;
- delays or changes in plans with respect to exploration or development projects or capital expenditures;
- volatility in market prices for oil and natural gas;

- uncertainties associated with estimating oil and natural gas reserves and the ability of the Company to realize value from its properties;
- geological, technical, drilling and processing problems;
- facility and pipeline capacity constraints and access to processing facilities and to market for production;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- marketing and transportation;
- prevailing weather and break-up conditions;
- environmental risks;
- competition for, among other things, capital, acquisition of reserves, undeveloped lands and skilled personnel;
- production and transportation costs and future development costs;
- the ability to access sufficient capital from internal and external sources; and
- changes in tax, royalty and environmental legislation.

Readers are cautioned that the foregoing list of risk factors is not exhaustive. The risk factors above should be considered in the context of current economic conditions, in particular low prices for all commodities produced by the Company, increased supply resulting from evolving exploitation methods, the attitude of lenders and investors towards corporations in the energy industry, potential changes to royalty and taxation regimes and to environmental and other government regulations, the condition of financial markets generally, as well as the stability of joint venture and other business partners, all of which are outside the control of the Company. Also to be considered are increased levels of political uncertainty and possible changes to existing international trading agreements and relationships. Legal challenges to asset ownership, limitations to rights of access and adequacy of pipelines or alternative methods of getting production to market may also have a significant effect on the Company's business. Additional information on these and other factors that could affect the business, operations or financial results of Tamarack are included in reports on file with applicable securities regulatory authorities, including but not limited to Tamarack's Annual Information Form for the year ended December 31, 2016, which may be accessed on Tamarack's SEDAR profile at www.sedar.com or on the Company's website at www.tamarackvalley.ca.

The forward-looking statements contained in this MD&A are made as of the date hereof and Tamarack undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Balance Sheets
(unaudited) (thousands)

	September 30, 2017	December 31, 2016
Assets		
Current assets:		
Accounts receivable	$26,776	$16,557
Prepaid expenses and deposits	245	1,369
Fair value of financial instruments (note 3)	6,019	–
	33,040	17,926
Property, plant and equipment (note 5)	1,171,810	601,420
Exploration and evaluation assets (note 6)	2,036	2,504
Deferred tax asset	–	41,714
	$1,206,886	$663,564
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$59,774	$25,015
Fair value of financial instruments (note 3)	–	10,704
	59,774	35,719
Bank debt (note 11)	162,164	45,227
Decommissioning obligations (note 7)	167,102	112,115
Deferred flow-through share premium	–	765
Deferred tax liability	34,690	–
Shareholders' equity:		
Share capital (note 9)	847,702	537,554
Contributed surplus	26,611	21,942
Deficit	(91,157)	(89,758)
	783,156	469,738
Commitments(note 13)		
	$1,206,886	$663,564

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Loss and Comprehensive Loss
For the three and nine months ended September 30, 2017 and 2016
(unaudited) (thousands, except per share amounts)

	Three months ended September 30,		Nine months ended September 30,	
	2017	2016	2017	2016
Revenue:				
Oil and natural gas	$63,927	$31,588	$193,512	$75,724
Royalties	(7,043)	(2,220)	(20,670)	(5,049)
Realized gain on financial instruments (note 3)	3,994	2,083	2,422	12,459
Unrealized gain (loss) on financial instruments (note 3)	(2,739)	(529)	16,991	(15,516)
	58,139	30,922	192,255	67,618
Expenses:				
Production	21,271	11,494	60,421	31,241
General and administration	3,057	1,872	9,047	5,405
Transaction costs (note 4)	–	500	5,663	596
Stock-based compensation (note 12)	1,052	827	3,223	2,689
Finance	2,668	1,409	7,702	3,946
Depletion, depreciation and amortization	38,943	17,108	106,883	47,536
	66,991	33,210	192,939	91,413
Loss before taxes	(8,852)	(2,288)	(684)	(23,795)
Deferred income tax recovery (expense)	2,110	(908)	(715)	4,397
Net loss and comprehensive loss	$(6,742)	$(3,196)	$(1,399)	$(19,398)
Net loss per share (note 10):				
Basic	$(0.03)	$(0.02)	$(0.01)	$(0.17)
Diluted	$(0.03)	$(0.02)	$(0.01)	$(0.17)

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Changes in Shareholders' Equity
(unaudited) (thousands)

	Number of common shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance at January 1, 2017	137,527	$537,554	$21,942	$(89,758)	$469,738
Issue of common shares	90,166	310,092	–	–	310,092
Share issue costs, net of tax of $5.5	–	(15)	–	–	(15)
Transfer on exercise of stock options	–	71	(71)	–	–
Stock-based compensation	–	–	4,740	–	4,740
Net loss	–	–	–	(1,399)	(1,399)
Balance at September 30, 2017	227,693	$847,702	$26,611	$(91,157)	$783,156

	Number of common shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance at January 1, 2016	99,971	$416,075	$17,044	$(61,935)	$371,184
Issue of common shares	35,104	117,337	–	–	117,337
Issue of flow-through shares	1,952	8,003	–	–	8,003
Share issue costs, net of tax of $1,790.2	–	(4,840)	–	–	(4,840)
Transfer on exercise of stock options	–	104	(104)	–	–
Flow-through share premium	–	(859)	–	–	(859)
Stock-based compensation	–	–	3,833	–	3,833
Net loss	–	–	–	(19,398)	(19,398)
Balance at September 30, 2016	137,027	$535,820	$20,773	$(81,333)	$475,260

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Cash Flows
For the three and nine months ended September 30, 2017 and 2016
(unaudited) (thousands)

	Three Months ended September 30,		Nine months ended September 30,	
	2017	2016	2017	2016
Cash provided by (used in):				
Operating:				
Net loss	$(6,742)	$(3,196)	$(1,399)	$(19,398)
Items not involving cash:				
Depletion, depreciation and amortization	38,943	17,108	106,883	47,536
Stock-based compensation	1,052	827	3,223	2,689
Accretion expense on decommissioning obligations	892	496	2,706	1,169
Unrealized loss (gain) on financial instruments	2,739	529	(16,991)	15,516
Deferred income tax expense (recovery)	(2,110)	908	715	(4,397)
Abandonment expenditures (note 7)	(314)	(2)	(675)	(187)
Changes in non-cash working capital (note 8)	777	(2,585)	7	199
Cash provided by operating activities	35,237	14,085	94,469	43,127
Financing:				
Change in bank debt	21,371	(32)	116,939	(34,224)
Proceeds from issuance of shares	–	81,606	–	125,340
Share issue costs	–	(4,247)	(21)	(6,630)
Cash provided by financing activities	21,371	77,327	116,918	84,486
Investing:				
Property, plant and equipment additions (note 5)	(70,828)	(13,972)	(147,933)	(39,713)
Exploration and evaluation additions (note 6)	(3,235)	(525)	(8,853)	(2,243)
Acquisitions (note 4)	(3,253)	(85,308)	(109,716)	(85,308)
Proceeds from disposal of property, plant and equipment	291	–	291	–
Changes in non-cash working capital (note 8)	20,417	8,393	54,824	(349)
Cash used in investing activities	(56,608)	(91,412)	(211,387)	(127,613)
Change in cash and cash equivalents	–	–	–	–
Cash and cash equivalents, beginning of period	–	–	–	–
Cash and cash equivalents, end of period	$ –	$ –	$ –	$ –

See accompanying notes to the condensed consolidated interim financial statements.

1. Reporting entity:

Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") is a corporation existing under the laws of Alberta. The Company is engaged in the exploration for, development and production of, oil and natural gas. The condensed consolidated interim financial statements of Tamarack consist of the Company and its subsidiaries. The Company has the following wholly owned subsidiaries, which are incorporated in Canada: Tamarack Acquisition Corp. and Tamarack Valley Ridge Holdings Ltd. The Company also has a subsidiary incorporated in the United States: Tamarack Ridge Resources Inc. On January 11, 2017, Tamarack Acquisition Corp. and Spur Resources Ltd., completed a vertical amalgamation under the *Business Corporations Act* (Alberta) to form "Tamarack Acquisition Corp.".

Tamarack is a publicly traded company, incorporated and domiciled in Canada. The address of its registered office is Suite 2500, 450 – 1st Street S.W., Calgary, Alberta, T2P 5H1. The address of its head office is currently Suite 600, 425 – 1st Street S.W., Calgary, Alberta T2P 3L8.

2. Basis of preparation:

(a) Statement of compliance:

The condensed consolidated interim financial statements have been prepared in accordance with International Accounting Standards 34, "Interim Financial Reporting" of International Financial Reporting Standards ("IFRS").

These condensed consolidated interim financial statements have been prepared following the same accounting policies and methods of computation as the annual consolidated financial statements of the Company for the year ended December 31, 2016. The disclosures provided below are incremental to those included with the annual consolidated financial statements and certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed or omitted. These condensed consolidated interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto in the Company's annual filings for the year ended December 31, 2016.

The condensed consolidated interim financial statements were authorized for issue by the Board of Directors on November 7, 2017.

(b) Future accounting pronouncements:

In July 2014, the International Accounting Standards Board ("IASB") completed the final elements of IFRS 9 "Financial Instruments." The Standard supersedes earlier versions of IFRS 9 and completes the IASB's project to replace IAS 39 "Financial Instruments: Recognition and Measurement." IFRS 9, as amended, includes a principle-based approach for classification and measurement of financial assets, a single 'expected loss' impairment model and a substantially-reformed approach to hedge accounting. The mandatory effective date of IFRS 9 is for annual periods on or after January 1, 2018, and must be applied retrospectively with some exceptions. Early adoption is permitted. The Company is evaluating the impact of this standard on the financial statements and does not anticipate a material change to the valuation of its financial assets.

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers", which replaces IAS 18 "Revenue", IAS 11 "Construction Contracts" and related interpretations. In July 2015, the IASB issued an amendment to IFRS 15, deferring the effective date by one year. IFRS 15 provides clarification for recognizing revenue from contracts with customers and establishes a single revenue recognition and measurement framework. The standard is required to be adopted either retrospectively or using a modified transition approach for fiscal years beginning on or after January 1, 2018, with earlier adoption permitted. The Company is evaluating the impact of this standard on the financial statements and does not anticipate it to have a material impact.

In January 2016, the IASB issued IFRS 16 "Leases". The new standard is effective for annual periods beginning on or after January 1, 2019. Earlier application is permitted for entities that apply IFRS 15 "Revenue from Contracts with Customers" at or before the date of initial adoption of IFRS 16. IFRS 16 will replace IAS 17 "Leases". This standard introduces a single lessee accounting model and requires a lessee to recognize assets and liabilities for all leases with a term of more than 12 months, unless the underlying asset is of low value. A lessee is required to recognize a right-of-use asset representing its right to use the underlying asset and a lease liability representing its obligation to make lease payments. The Company is evaluating the impact of the standard on the Company's financial statements.

3. Commodity contracts:

It is the Company's policy to economically hedge some oil and natural gas sales using various financial derivative forward sales contracts and physical sales contracts. The Company does not apply hedge accounting for these contracts. The Company's production is usually sold using "spot" or near term contracts, with prices fixed at the time of transfer of custody or based on a monthly average market price. The Company, however, may give consideration in certain circumstances to the appropriateness of entering into long-term, fixed price marketing contracts. The Company does not enter into commodity contracts other than to meet its expected sales requirements.

All financial derivative contracts are classified as fair value through profit and loss and are recorded on the balance sheet at fair value. The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and level 2 published forward price curves as at the balance sheet date, using the remaining contracted oil and natural gas volumes and a risk-free interest rate (based on published government rates). The fair value of options and collars is based on option models that use level 2 inputs, being published information with respect to volatility, prices and interest rates. The derivatives are valued at fair value to profit and loss and therefore the carrying amount equals fair value.

At September 30, 2017, the Company held derivative commodity and financial contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price	Fair value (Cdn $000s)
Crude oil	2,000 bbls/day	October 1, 2017 – December 31, 2017	WTI fixed price	Cdn $70.83	$1,116
Crude oil	600 bbls/day	October 1, 2017 – December 31, 2017	WTI fixed price	US $55.08	$213
Crude oil	600 bbls/day	October 1, 2017 – December 31, 2017	WTI written call option	Cdn $81.90	–
Crude oil	200 bbls/day	January 1, 2018 – March 31, 2018	WTI fixed price	Cdn $73.50	$150
Crude oil	1,700 bbls/day	January 1, 2018 – March 31, 2018	WTI fixed price	US $53.11	$187
Crude oil	1,500 bbls/day	April 1, 2018 – June 30, 2018	WTI fixed price	US $51.90	$(13)
Crude oil	900 bbls/day	July 1, 2018 – September 30, 2018	WTI fixed price	US $51.80	$(7)
Crude oil	700 bbls/day	October 1, 2018 – December 31, 2018	WTI fixed price	US $51.93	$40
Natural gas	25,000 GJ/day	October 1, 2017 – December 31, 2017	AECO fixed price	Cdn $2.91	$2,131
Natural gas	25,000 GJ/day	January 1, 2018 – March 31, 2018	AECO fixed price	Cdn $3.16	$1,527
Foreign exchange	995,000 US$/mth	October 1, 2017 – March 31, 2018	Exchange rate	Cdn $1.35	$675
					$6,019

At September 30, 2017, the commodity contracts were fair valued with an asset of $6.0 million (December 31, 2016 - $10.7 million liability) recorded on the balance sheet and an unrealized gain of $17.0 million recorded in earnings for the nine months ended September 30, 2017.

All physical commodity contracts are considered executory contracts and are not recorded at fair value on the balance sheet. On settlement, the realized benefit or loss is recognized in oil and natural gas revenue. At September 30, 2017, the Company held the following physical commodity contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	1,000 bbls/day	October 1, 2017 – December 31, 2017	WTI/Edm Differential	US $3.25
Crude oil	1,500 bbls/day	October 1, 2017 – December 31, 2017	WTI/Edm Differential	US $3.20
Crude oil	45,000 bbls/month	October 1, 2017 – December 31, 2017	WTI/Edm Differential	US $3.00

The assets and liabilities of risk management contracts are offset and the net amount presented on the balance sheet when the Company has a legal right to offset the amounts and intends to settle them on a net basis or to realize the asset and settle the liability simultaneously.

The following table sets out gross amounts relating to risk management contract assets and liabilities that have been presented on a net basis on the balance sheet:

Gross Amounts (thousands)	**September 30, 2017**	December 31, 2016
Risk management contracts		
Current asset	**$6,039**	$ –
Current liability	**(20)**	(10,704)
Balance, end of the period	**$6,019**	$(10,704)

Since September 30, 2017, the Company has entered into the following derivative contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude Oil	1,800 bbls/day	January 1, 2018 – March 31, 2018	WTI fixed price	US $53.65
Crude Oil	1,800 bbls/day	April 1, 2018 – June 30, 2018	WTI fixed price	US $53.24
Crude Oil	1,500 bbls/day	July 1, 2018 – September 30, 2018	WTI fixed price	US $53.04
Crude Oil	700 bbls/day	October 1, 2018 – December 31, 2018	WTI fixed price	US $53.04
Foreign Exchange	600,000 US$/ month	January 1, 2018 – March 31, 2018	Exchange Rate	Cdn $1.2584
Foreign Exchange	720,000 US$/ month	April 1, 2018 – June 30, 2018	Exchange Rate	Cdn $1.2869

4. Corporate acquisition:

On January 11, 2017, Tamarack acquired Spur Resources Ltd. (“Spur”) by acquiring all of the issued and outstanding common shares of Spur with the issuance of 90.1 million common shares of the Company and $58.0 million of cash (the “Viking Acquisition”). The Viking Acquisition builds upon the Company's existing Viking asset base at Redwater and core Cardium assets at Wilson Creek. The operations from the Viking Acquisition have been included in Tamarack’s results commencing on January 11, 2017. Based upon Tamarack’s share price on the date of closing being January 11, 2017 of $3.44 per share, the total consideration paid by Tamarack was approximately $368.1 million.

The Company incurred transaction costs of $5.7 million in connection with the Viking Acquisition which is recorded in earnings.

The Viking Acquisition has been accounted for as a business combination using the acquisition method of accounting, whereby the assets acquired and the liabilities assumed are recorded at the estimated fair value on the acquisition date of January 11, 2017. The allocation of the purchase price, based on management's estimate of fair values, is as follows:

Consideration (thousands):		
Cash consideration	$	57,972
Share consideration (90,142,906 common shares)		310,092
Total consideration	$	368,064
Net Assets Acquired (thousands):		
Current assets	$	39,684
Current liabilities		(10,517)
Risk management contracts		(269)
Bank debt		(47,115)
Property, plant and equipment		480,417
Decommissioning obligations		(19,207)
Deferred tax liability		(74,929)
Net assets	$	368,064

The fair value of property, plant and equipment has been estimated with reference to an independently prepared reserves evaluation for the acquired properties. The fair value of decommissioning obligations was initially estimated using a credit-adjusted risk-free rate of 8% and subsequently revalued using the risk-free rate (see note 7).

Oil and natural gas revenue of $46.8 million and a net loss of $3.6 million are included in the statement of loss for the Viking Acquisition properties since the closing date of January 11, 2017.

If the acquisition had occurred on January 1, 2017, the incremental oil and natural gas revenue and loss recognized for the period ended September 30, 2017 and the pro forma results would have been as follows:

Period ended September 30, 2017 (thousands)	As stated	Spur Resources Ltd. Prior to Acquisition	(unaudited) Pro Forma
Oil and natural gas revenue	$193,512	$2,616	$196,128
Net loss	(1,399)	(227)	(1,626)

(1) This pro forma information is not necessarily indicative of results of operations that would have resulted had the acquisition been effected on the dates indicated.

5. Property, plant and equipment:

($ thousands)	Oil and Natural gas Interests	Other Assets	Total
Cost:			
Balance at January 1, 2016	$716,388	$601	$716,989
Property acquisition	105,093	–	105,093
Cash additions	53,401	433	53,834
Decommissioning costs	28,622	–	28,622
Stock-based compensation	1,479	–	1,479
Transfer from exploration and evaluation assets	1,212	–	1,212
Disposals	(7,025)	–	(7,025)
Balance at December 31, 2016	899,170	1,034	900,204
Corporate acquisition (note 4)(1)	484,755	–	484,755
Cash additions	147,624	309	147,933
Decommissioning costs	33,749	–	33,749
Stock-based compensation	1,516	–	1,516
Transfer from exploration and evaluation assets	8,730	–	8,730
Balance at September 30, 2017	$1,575,544	$1,343	$1,576,887
Depletion, depreciation and impairment losses:			
Balance at January 1, 2016	$235,109	$265	$235,374
Depletion and depreciation	64,494	173	64,667
Disposals	(1,257)	–	(1,257)
Balance at December 31, 2016	298,346	438	298,784
Depletion and depreciation	106,125	168	106,293
Balance at September 30, 2017	$404,471	$606	$405,077

	Oil and Natural gas Interests	Other Assets	Total
Carrying amounts:			
At December 31, 2016	$600,824	$596	$601,420
At September 30, 2017	$1,171,073	$737	$1,171,810

(1) Includes $4.3 million of minor property acquisitions net of dispositions.

The calculation of depletion at September 30, 2017 includes estimated future development costs of $530 million (December 31, 2016 – $401 million) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $43.1 million (December 31, 2016 – $32.8 million).

6. Exploration and evaluation assets:

($ thousands)	Total
Cost:	
Balance at January 1, 2016	$22,083
Additions	2,985
Transfer to property, plant and equipment	(1,212)
Balance at December 31, 2016	23,856
Additions	8,853
Transfer to property, plant and equipment	(8,730)
Balance at September 30, 2017	$23,979
Amortization and impairment:	
Balance at January 1, 2016	$19,878
Amortization	760
Impairment loss	715
Balance at December 31, 2016	21,353
Amortization	590
Balance at September 30, 2017	$ 21,943

	Total
Carrying amounts:	
At December 31, 2016	$2,504
At September 30, 2017	$2,036

Exploration and evaluation ("E&E") assets consist of the Company's exploration projects which are pending the determination of proven or probable reserves. Additions represent the Company's share of costs incurred on E&E assets during the period.

7. Decommissioning obligations:

The decommissioning obligations result from net ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted and uninflated amount of cash flows required to settle its decommissioning obligations to be approximately $173.0 million at September 30, 2017 (December 31, 2016 – $114.3 million), which is expected to be incurred between 2018 and 2041. A risk-free rate of 2.5% (December 31, 2016 – 2.3%) and an inflation rate of 2% (December 31, 2016 – 2%) is used to calculate the present value of the decommissioning obligations at September 30, 2017 as presented in the table below:

($ thousands)	**September 30, 2017**	December 31, 2016
Balance, beginning of the period	**$112,115**	$63,331
Liabilities incurred	**8,207**	1,546
Liabilities acquired (note 4)	**19,207**	20,782
Change in estimates	**(3,659)**	(5,970)
Change in discount rate on acquisition	**29,201**	33,045
Expenditures	**(675)**	(218)
Liabilities disposed	**–**	(2,097)
Accretion	**2,706**	1,696
Balance, end of the period	**$167,102**	$112,115

The decommissioning obligations acquired in the Viking Acquisition were initially recognized using a credit-adjusted risk-free discount rate of 8%. It was subsequently revalued using the risk-free rate noted above resulting in the change in discount rate on acquisition in the above table with the offset to property, plant and equipment.

The change in estimates for 2017 resulted from decommissioning obligations being revalued using a risk-free rate of 2.5% as opposed to the risk-free rate of 2.3% used in 2016.

8. Supplemental cash flow information:

Changes in non-cash working capital consists of:

	Three months ended September 30,		Nine months ended September 30,	
(thousands)	**2017**	2016	**2017**	2016
Source/(use of cash):				
Accounts receivable	**$237**	$(136)	**$(10,219)**	$1,591
Prepaid expenses and deposits	**1,727**	(363)	**1,124**	(303)
Accounts payable and accrued liabilities	**19,230**	5,558	**34,759**	(2,187)
Working capital acquired (note 4)	**–**	749	**29,167**	749
	$21,194	$5,808	**$54,831**	$(150)
Related to operating activities	**$777**	$(2,585)	**$7**	$199
Related to investing activities	**$20,417**	$8,393	**$54,824**	$(349)

Cash interest paid during the quarter was $1.8 million and for the nine months ended September 30, 2017 was $5.0 million (December 31, 2016 – $3.4 million).

9. Share capital:

At September 30, 2017, the Company was authorized to issue an unlimited number of common shares and preferred shares without nominal or par value.

On January 11, 2017, the Company issued 90.1 million common shares in connection with the Viking Acquisition (note 4).

On December 29, 2016, the Company issued 0.5 million flow-through common shares, related to Canadian exploration expenditures, at $5.00 per share for total gross proceeds of $2.5 million. Under the terms of the flow-through share agreements, the Company is required to incur the expenditures by December 31, 2017. As of September 30, 2017, the Company has incurred the full $2.5 million of qualifying expenditures.

During the nine months ended September 30, 2017 there were 23,001 restricted share awards converted to common shares.

10. Loss per share:

The following table summarizes the net loss and weighted average shares used in calculating the net loss per share:

	Three months ended September 30,		Nine months ended September 30,	
(thousands, except per share amounts)	**2017**	2016	**2017**	2016
Net loss	**$(6,742)**	$(3,196)	**$(1,399)**	$(19,398)
Weighted average shares - basic	**227,691**	134,382	**224,376**	117,263
Weighted average shares - diluted	**227,691**	134,382	**224,376**	117,263
Net loss per share-basic	**$(0.03)**	$(0.02)	**$(0.01)**	$(0.17)
Net loss per share-diluted	**$(0.03)**	$(0.02)	**$(0.01)**	$(0.17)

Per share amounts have been calculated using the weighted average number of shares outstanding. For the three and nine months ended September 30, 2017, 9.9 million stock options, preferred shares and restrictive stock units were excluded from the diluted earnings per share as they were anti-dilutive. For the three and nine months ended September 30, 2016, 7.6 million stock options, preferred shares and restrictive stock units were excluded from the diluted earnings per share as they were anti-dilutive.

11. Bank debt:

The Company currently has available a revolving credit facility in the amount of $245 million and a $20 million operating facility (collectively the “Facility”) with a syndicate of lenders. The Facility, totaling $265 million, lasts for a 364 day period and will be subject to its next 364 day extension by May 25, 2018. If not extended on May 25, 2018, the Facility will cease to revolve and all outstanding balances will become repayable in one year from that extension date being May 25, 2019.

The interest rate on the Facility is determined through a pricing grid that categorizes based on a net debt to cash flow ratio as defined in the Facility. The interest rate will vary from a low of the bank's prime rate plus 1.0%, to a high of the bank’s prime rate plus 2.5%. The standby fee for the Facility will vary as per a pricing grid from a low of 0.5% to a high of 0.875% on the undrawn portion of the Facility. The Facility has been secured by a $550 million supplemental debenture with a floating charge over all assets. As the available lending limits of the Facility are based on the bank’s interpretation of the Company’s reserves and future commodity prices, there can be no assurance as to the amount of available facilities that will be determined at each scheduled review. The next review is scheduled for November 2017.

At September 30, 2017, the Company had utilized the Facility in the amount of $162.2 million. The interest rate applicable to the drawn amounts as of this date was 4.45%. As at September 30, 2017, the Company had letter of guarantees outstanding in the amount of $0.2 million against the Facility.

12. Share-based payments:

(a) Preferred share plan:

There are 1.2 million preferred shares of Tamarack Acquisition Corp. outstanding which are exchangeable into 1.1 million common shares of the Company (December 31, 2016 – 1.1 million). The preferred shares of Tamarack Acquisition Corp. are fully vested at September 30, 2017 and are exchangeable into common shares of the Company at an exchange price of $3.12 per common share. An exchange of the preferred shares is at the election of the Company under certain circumstances.

(b) Stock option plan:

Under the Company's stock option and restricted share unit plan it may grant up to 22.8 million options or restricted share units to its employees, directors and consultants of which 8.8 million options and restricted stock units have been issued that apply against this maximum amount. Stock options are granted at the market price of the shares at the date of grant, have a five-year term and vest one-third on each of the first, second and third anniversaries from the date of grant. There were 0.1 million options granted during the nine months ended September 30, 2017.

The fair value of each option granted during the nine months ended September 30, 2017 was estimated on the date of grant using the Black-Scholes option pricing model. The weighted average fair value and weighted average assumptions used to fair value the options are as follows:

	2017
Risk free rate (%)	**1.02**
Expected volatility (%)	**80**
Expected life (years)	**5**
Forfeiture rate (%)	**–**
Dividend ($ per share)	**–**
Fair value at grant date ($ per option)	**2.00**

The number and weighted average exercise prices of stock options under the plan are as follows:

	Number of options (thousands)	Weighted average exercise price
Outstanding, January 1, 2016	4,669	$ 3.59
Granted	945	3.44
Exercised	(16)	2.06
Expired	(271)	4.55
Outstanding, December 31, 2016	5,327	$ 3.52
Granted	140	3.01
Outstanding, September 30, 2017	**5,467**	**$ 3.50**

The following table summarizes information about stock options outstanding and exercisable at September 30, 2017:

	Options outstanding			Options exercisable	
Range of exercise price	Number outstanding (thousands)	Weighted average exercise price	Weighted average remaining contractual life (years)	Number exercisable (thousands)	Weighted average exercise price
$ 1.86 – 3.00	1,827	$2.38	1.4	1,324	$2.23
$ 3.01 – 5.00	3,174	$3.66	2.2	2,096	$3.73
$ 5.01 – 6.82	466	$6.82	1.9	466	$6.82
$ 1.86 – 6.82	**5,467**	**$3.50**	**1.9**	**3,886**	**$3.59**

(c) Restricted stock unit plan:

The Company has a restricted stock unit plan that allows the Board of Directors to grant restricted share awards to directors, officers and employees. Subject to terms and conditions of the restricted stock unit plan, each restricted share award entitles the holder to an award value to be paid as to one-third on each of the first, second and third anniversaries of the date of grant. There were 0.3 million restricted stock units granted during the nine months ended September 30, 2017.

For the purpose of calculating share-based compensation, the fair value of each award is determined at the grant date using the closing price of the common shares. On the date of exercise, the Company has the option of settling the award value in cash or in common shares of the Company.

The following table summarizes information about the restricted share awards:

	Number of awards (thousands)
Outstanding, January 1, 2016	1,861
Granted	1,214
Exercised	(12)
Outstanding, December 31, 2016	3,063
Granted	267
Exercised	(23)
Outstanding, September 30, 2017	**3,307**
Exercisable, September 30, 2017	**866**

13. Commitments:

The following table summarizes the Company's commitments at September 30, 2017:

($ thousands)	2017	2018	2019	2020	2021	2022	2023
Office lease	159	542	542	263	–	–	–
Take or pay commitments(1)	247	986	–	–	–	–	–
Rental fee(2)	1,293	5,170	5,170	5,170	5,170	3,299	714
Total	1,699	6,698	5,712	5,433	5,170	3,299	714

(1) Pipeline commitment to deliver a minimum of 300 m3/d of crude oil/condensate subject to a take-or-pay provision of $9.00/m3. The remaining term is 15 months.

(2) Rental fee of $0.3 million per month for a maximum period of 90 months starting in January 2015 relating to four facilities and rental fee of $0.1 million per month for a maximum period of 90 months starting in January 2016 relating to four facilities.

CORPORATE INFORMATION

Directors

Floyd Price - Chairman(3)

Dean Setoguchi(1)

David Mackenzie(1)(2)

Jeff Boyce(1)(2)

Noralee Bradley(3)(4)

John Leach(1)(3)

Ian Currie(2)(4)

Rob Spitzer(3)(4)

Brian Schmidt

(1) Member of the Audit Committee of the Board of Directors
(2) Member of the Reserves Committee of the Board of Directors
(3) Member of the Compensation & Governance Committee of the Board of Directors
(4) Member of the Health, Safety & Environmental Committee of the Board of Directors

Management Team

Brian Schmidt
President & Chief Executive Officer

Ron Hozjan
VP Finance & Chief Financial Officer

Dave Christensen
VP Engineering

Ken Cruikshank
VP Land

Kevin Screen
VP Production & Operations

Scott Reimond
VP Exploration

Sony Gill
Corporate Secretary

Lead Bank Syndicate

National Bank of Canada

Legal Counsel

McCarthy Tétrault

Auditor

KPMG LLP

Stock Exchange

Toronto Stock Exchange
Stock symbol: TVE

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